

Independent Analysis of Prices Required for Vermont's Standard Offer

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1. Introduction and Purpose

Power Advisory LLC (Power Advisory) was engaged by the Vermont Public Service Board (Board or PSB) to serve as the Technical Advisor and assist the Board fulfill their responsibilities pursuant to Act 45 of 2009 (Act or Statute). The Act directed the Board to determine whether the rates contained in the statute represented a “reasonable approximation” of the costs using criteria contained in the statute. A Subgroup (Cost Analysis Subgroup) was established to advise the Board with these determinations. The Subgroup elected to use a cash flow model to estimate the nominal levelized rate which would provide the target after tax return on equity. Two sets of input assumptions were used to develop two sets of standard offer prices. The “initial” input assumptions were received primarily from the project developers or their representatives. A second set of assumptions were provided by the Department of Public Service (Department), and included information gleaned from the Clean Energy Development Fund applications and other data sources available to the Department. On August 28, 2009 a final report on recommendations of the Cost Analysis Subgroup was issued. This report reflected considerable divergence of opinions among Cost Analysis Subgroup members regarding the appropriate technology cost, performance and financing assumptions and the resulting Standard Offer prices.¹ Given this lack of consensus the Board staff member who chaired the Cost Analysis Subgroup requested that Power Advisory provide its expert opinion regarding the costs, operating performance, and financing assumptions for the various renewable technologies to which the Act applies. This report provides Power Advisory’s best estimate regarding these assumptions and the resulting Standard Offer prices produced by the cash flow model when employing these assumptions. We submitted an initial draft report to the PSB on September 3rd and subsequently updated the report, where necessary, to reflect comments offered on the Cost Analysis Subgroup report.

The review and assessment of these assumptions was constrained by the project budget and time available. As a result Power Advisory wasn’t able to perform more detailed research and analysis regarding these project assumptions.

¹ This report is available at http://psb.vermont.gov/sites/psb/files/docket/7523/CostAnalysis/Subgroup_with_Technical_Corrections_8_31_09.pdf. The positions of the parties are reviewed in the Subgroup Report and aren’t restated in this report. Where appropriate this report draws upon the Subgroup Report.

2. Approach and High Level Assumptions

2.1 Overview of Financial Modeling Approach

Power Advisory's pricing analysis is based on a cash flow model which was initially developed by Green Mountain Power (GMP) and used for the Cost Analysis Subgroup modeling analyses. The basic structure of the model is to determine a revenue stream over a given contract period that allows a company to recover the costs of building and operating a renewable energy generation project. The model calculates a price to be charged per megawatt hour yielding an annual cash flow stream. Annual cash expenditures, based on cost and performance assumptions, are subtracted from the cash inflows to produce a net annual cash flow number. The annual after tax cash flows are used to calculate an internal rate of return (IRR) earned by the equity investor on the generation project. The Act prescribes the equity investor earn a return of no less than 12.13%, unless adjusted by the Board to achieve the statutory objective of rapid installation and deployment. The model is solved by inputting a price that produces a 12.13% IRR based on the present value of after tax cash flows.

There are a number of critical policy questions that underlie the assumptions in this analysis. These include: (1) the criteria that should be employed when selecting appropriate assumptions; and (2) the level of granularity that should be used when establishing the standard offer prices within a technology classification.

2.2 Objectives and Criteria for Establishing Assumptions

The Act directs the Board to adjust "costs and rate of return on equity ...to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive."² This language suggests that the objective of incenting rapid development and commissioning of plants must be balanced by setting prices at a level that does not exceed this amount. How this balance should be achieved is a critical issue and was discussed by various subgroup members, many of which argued for a "cautious approach".³ Power Advisory believes that such caution is warranted given the limited time available for the subgroup to review and assess these technology assumptions, the risks associated with embedding above "market" prices that will be borne by Vermont consumers over the 20 year or more term of the power purchase agreements, and the ability to have a more fulsome review of generation technology costs and assumptions in the second phase of this undertaking as provided by the Act.

2.2.1 Granularity

One of the critical policy assumptions that will guide this pricing analysis is whether separate prices should be established for different size projects within a technology classification. Act 45 only specifies interim prices for different size wind projects and here the distinction is between wind projects with a rated capacity of 15 kW or less and less than 2.2 MW projects. However, the Act does indicate that the Board shall "consider different generic costs for subcategories of different plant capacities within each category of generation technology."⁴

² Sec. 3. 30 V.S.A. §8005 (2)(B)(i)(III).

³ This includes the Department, GMP, Central Vermont Public Service, IBM, Group of Municipal Electric Utilities, Burlington Electric Department, Associated Industries of Vermont, and Vermont Public Interest Research Group.

⁴ Sec. 3. 30 V.S.A. §8005 (2)(B)(i)(I)(bb).

The resolution of the granularity issue will be driven by objectives which are best assessed by the Board. We don't offer an opinion on this issue. For our analysis we used the granularity distinctions that were applied by the Department in its cost analysis. They employed the greatest granularity; although the Department doesn't advocate additional granularity beyond the one size category specified in the Act.

2.3 Taxes

The federal and state governments have provided generous tax benefits to promote the adoption of renewable energy projects. Consideration of these tax benefits is critical to the modeling of the cash flows of these renewable generation projects. Also critical are the assumptions regarding the ability of the generation project developer to utilize fully these tax benefits (i.e., the net operating losses provided by accelerated depreciation and/or investment tax credits). For purposes of the modeling, the project developers were assumed to be for-profit institutions that could take full advantage of federal tax incentives and utilize a significant portion of the state tax incentives.⁵ The assumed federal tax rate was 35% and the assumed state income tax rate was 8.5%, for a combined income tax rate of 40.53%. A 20% federal and 5% state income tax rate was assumed for the largest farm methane projects and 15% federal and 5% state income tax rate was assumed for the medium and small farm methane projects. Given the significant tax benefits from these projects assuming the highest tax rate is likely to decrease the rate of return for those in lower brackets. Assuming a lower rate will likely increase the rate of return for those in higher tax brackets.

Act 45 specifically directs the Board when evaluating standard offer rates to consider reasonably available tax credits and other incentives provided by federal and state governments and other sources applicable to the generation technology. The assumptions regarding the treatment of the different tax incentives are outlined below.

2.3.1 Investment Tax Credit

The Federal Investment Tax Credit (ITC) for renewable energy production allows for a credit equal to 30 percent of the cost of the installation (less any non-qualifying costs such as transmission interconnection costs) for wind and solar projects. However, this non-refundable credit requires taxable income. For businesses not having sufficient income, the credit value can be taken over several years. Power Advisory assumed that the full value of the Federal ITC can be utilized in the first year for all assumed applicable costs (generally 90 to 95% of initial capital costs).⁶

The state of Vermont provides a 30 percent income tax credit for photovoltaic installations on business property (equivalent to the federal definition for claiming the Investment Tax Credit). This credit is available to corporations and individuals receiving income from businesses. There are limitations to the Vermont credit that are more restrictive than the Federal ITC for solar installations: (1) the basis of the credit is reduced for projects that receive grant funding and the credit is not available if the project has received funding from the Clean Energy Development Fund (CEDF); (2) the credit can be carried forward for a maximum of five years and does not have value to taxpayers without a Vermont income tax liability; and (3) the credit is not available if the project has opted to take a US Treasury grant instead of the federal ITC. The Vermont Tax Department representative recommended that 50% of the credit be taken over five-years. Penn Energy Trust recommends that no credit be taken for the state solar ITC because developers are more likely to take advantage of the US Treasury grant which would preclude them for receiving the state solar ITC. This is an inefficient utilization of these tax incentives and would result in

⁵ We assumed that it would be more difficult for developers to utilize fully state tax incentives because they would need offsetting net income in Vermont.

⁶ This ITC generally covers costs associated with the generation technology itself. For example, costs associated with the transmission interconnection are not covered.

higher cost projects or higher returns for developers. Power Advisory assumed that the full credit was taken over a five-year period, recognizing that few developers are likely to be able to fully utilize the ITC in one year.

Vermont also offers a state investment tax credit for individuals filing income tax returns (this includes individuals receiving pass through income from Partnerships and S-Corps, but not corporate income tax returns) that allows them to take 24 percent of the value of the Federal ITC on energy investments. As an ITC, the credit has value only for those investors and partners that have a Vermont income tax liability. Given the Business Solar Tax Credit, the Vermont ITC applies to wind and other eligible non-solar energy projects. Given the constraints on the utilization of this credit, in particular the constraint on its utilization in corporate income tax returns, Power Advisory assumed that 50% of the credit is taken over a two-year period.⁷

2.3.2 Vermont Clean Energy Development Fund

The CEDF is not a tax credit, however, for solar installations, a grant from the fund precludes the recipient from benefiting from the Vermont Business Solar Tax Credit. In the past, the CEDF has provided \$250,000 for solar installations of 50-75 kW. The Small Scale Renewable Energy Incentive is available to smaller projects (<15 kW). The incentive is provided at a set rate of \$1.75 per watt for solar projects and \$2.50/watt for wind projects.

The Department argued that CEDF grants should be considered in the cost analysis. The Department indicated that the CEDF had a budget of approximately \$10 million for its grant program. Assuming that all projects received the maximum \$250,000 grant, the CEDF could fund 40 projects. Given the 50 MW represented by the standard offer this represents an average project size of 1.25 MW which isn't unreasonable given the likely more compelling project economics offered by larger projects. The availability of these grants will depend on the policy of the CEDF's independent board. Power Advisory is concerned that without a formal decision of this Board that it won't offer grants to standard offer projects, if the CEDF grant isn't reflected in our analysis then developers could be able to "double dip" and receive this grant and realize a return higher than 12.13%. Therefore, given our cautious approach we have elected to assume that developers of small wind and farm methane projects receive the CEDF grant.⁸ However, we assumed that larger wind (i.e., 1.5 MW), solar, and hydro project developers wouldn't receive the CEDF grant. Great Bay Hydro Corporation indicated that it requested a CEDF grant for its project, but was denied a grant given that the project could be funded by other means.⁹ The larger wind project was among the more cost-effective technologies evaluated. Therefore, we assumed that the CEDF might apply similar logic for larger wind projects. As discussed, solar projects aren't eligible for a grant if they utilize the solar ITC. Given our assumption that only a few of the eligible standard offer technologies would receive grants, the budget of \$10 million is more likely to be adequate.

2.3.3 Depreciation Assumptions

The calculation of after tax cash flows for a business includes the use of depreciation as a business expense. The time value of money and rates of return influence the choice of the time frame over which to

⁷ A two-year period was used for this ITC given that it only represents a smaller amount than available to solar projects, making it more likely that parties would be able to utilize the ITC more quickly.

⁸ If the CEDF board announces a policy that it will preclude projects that participate in the standard offer program from receiving CEDF grants we can update the required pricing for the Board.

⁹ A CEDF Board member indicated to the Cost Analysis Subgroup that a fundamental criterion that the CEDF applied when assessing whether to award grants was "but for" this grant would the project otherwise not be developed. Projects that satisfied this criterion were more likely to be awarded grants.

depreciate any assets, including the energy production facilities supported through the Standard Offer. The IRS has rules restricting the rates of depreciation, and recent changes in the law allow for accelerated depreciation which will influence the accounting practices for energy investments. In general, accelerating depreciation decreases the income tax liability for the current year while increasing the liability for later years. Power Advisory used the same depreciation schedules which were used in the Cost Analysis Subgroup modeling which reflect accelerated depreciation for the equipment and standard depreciation for building and other property.

2.3.4 Vermont Property Tax

Energy production facilities are subject to property taxes. Property tax valuation is the basis for the Education Property Tax assessment that is paid to the state. The valuation is also the basis for paying a municipal property tax to the municipality in which the facility is located. Valuing property is the responsibility of a local municipality. The state does provide guidance on valuing property types. In the DPS model runs, the Department decreases the property tax to reflect the declining value of the renewable assets as their remaining contract value decreases and the equipment depreciates. Power Advisory modeled the capitalization approach recommended by the Vermont state tax department and found that it produced results were close to that produced by the DPS methodology. Therefore, Power Advisory employed the DPS methodology for establishing property taxes.

2.4 Cost of Capital

The cost of capital for these projects is comprised of both a debt and equity component. Key assumptions include the capital structure, the cost of debt, and the cost of equity. The basis for each of these assumptions is reviewed below.

2.4.1 Capital Structure

Power Advisory modeling assumed that most developers would use a non-recourse project finance structure to finance their projects.^{10,11} Under this structure, the debt is underpinned solely by project cash flows. The leverage allowed by lenders is based on debt service coverage ratios (the ratio of EBITDA, earnings before interest, taxes, depreciation and amortization and debt service (interest and principal payments)), with the required debt service coverage ratio based on project risks. An average debt service coverage ratio of 1.5 is commonly used, with a minimum debt service coverage ratio of 1.2 typically required. Rather than sculpt principal payments to meet this minimum 1.2 debt service coverage ratio as would be typical, given that this is a screening analysis Power Advisory focused on ensuring that the capital structure provided the average debt service coverage ratio of 1.5.

This resulted in projects having a 50/50 to 70/30 debt/equity ratio.

The smaller solar PV (500 kW and smaller) and farm methane projects were not assumed to use non-recourse debt which is typically used in project finance and as such didn't require such a high debt

¹⁰ Given the significant investment tax credits offered by these projects, developers are also likely to employ tax equity structures where parties that can fully utilize the project tax benefits are brought into the project. Banks have been major players in the tax equity market. However, with many banks and other equity investors incurring losses and acquiring firms with significant losses, there is a more limited pool of equity investors. This may drive up the "cost" of tax equity.

¹¹ Farm methane projects were assumed to utilize a more conventional mortgage secured by the property value of the farm (or a portion thereof).

coverage ratio. These projects are more likely to be financed using the real property and improvements as the collateral.

2.4.2 Cost of Equity

Based upon the relevant Board order the minimum return on equity to meet the statutory requirements is 12.13 percent.⁹

2.4.3 Cost and Tenor of Debt

The cost of debt (interest rate) for technologies that were project financed was assumed to be 7.5%. This is an increase relative to the initial and DPS modeling assumptions. Under such a project finance structure lenders will establish the cost of debt based on their assessment of the project's overall risk and general credit market conditions at the time of the financing. With the program underpinned by legislation and a Board order approving the contract, there is likely to be relatively limited regulatory risk. The ultimate buyers for the power are the Vermont Distribution Utilities. There isn't a single counterparty; this should reduce the perceived credit risks to the seller. Therefore, it is believed that the standard offer contract will not be viewed as unduly risky by lenders.

A more challenging question is the likely condition of credit markets when these projects are financed. Conditions in the credit markets have improved significantly over the last several months. A significant number of electric utilities have issued debt at reasonable terms and high quality generation projects (i.e., fully contracted with attractive credits) are getting financed. Given the considerable improvement in the condition of the credit markets over the last six months, likelihood for continued improvement, and recognizing that the terms available (e.g., loan tenor and credit spreads) were more favorable prior to the implosion of the credit markets, the cash flow modeling assumptions reflect continued improvement in credit market conditions.

Support for the 7.5% debt rate is provided by the fact that a number of utilities have been able to secure debt of equivalent and longer terms at such rates. The DPS notes that available commercial loan rates (for mortgages ranging from \$500k to \$1.5 M) had rates between 6.5 and 6.75 (for a 7-year term loan). Another recent point of reference is a 40 MW wind project in Ontario which has a 20-year standard offer contract with the Ontario Power Authority (OPA). This project was able to secure a 6.4% debt rate, after employing an interest rate swap to lock in the rate. While the term of the loan was only five years, the debt was amortized over a 19-year term. This cost of debt and amortization schedule suggests that our assumptions are conservative. However, lenders have considerable experience with the OPA standard offer contract and may view an Ontario contract as having less change-in-law risk. In addition, the term of this loan is only five years, supporting a lower interest rate. Finally long-term interest rates in Canada are about 25 basis points lower than in the US.

While the tenors (term of debt) of recent project financings have ranged up to 7 to 8 years, the debt repayment schedule is typically amortized over a longer term. The initial modeling using proponent assumptions assumed an 18-year loan, except for the farm methane projects which assumed a seven-year term. The seven-year term for farm methane projects reflected that the loan is secured on the value of the farm. The financial modeling assumes that projects will be able to amortize loans over 18 (initial modeling of proponent assumptions) to 25-years (DPS modeling of solar projects). While tenors of this length are not currently available, higher quality loans are being amortized over 15 to 19 years. Power Advisory assumed an 18-year term for all loans except for farm methane. In general, Power Advisory's debt financing assumptions assume continued improvement in credit market conditions by the time projects need to secure financing.

3. Evaluation of Standard Offer Rates

This chapter presents Power Advisory's estimates of the Standard Offer rates that would produce a 12.13 after return on equity. Each of the different renewable generation technologies that are identified in the Act along with the different size classifications that were considered by the Cost Analysis Subgroup are reviewed below.

3.1 Wind

Table 1 below summarizes the assumptions and modeling results (i.e., levelized price over the 20-year term of the contract in \$/MWh) for the two different project sizes that were evaluated: (1) a 1.5 MW wind turbine which is representative of a single commercial scale wind turbine; and (2) a 100 kW wind turbine which is consistent with Northern Power System's (Northern Power's) Northwind 100.¹² A less than 15 kW wind turbine wasn't evaluated given that data for such a project weren't readily available. The original assumptions for the 1.5 MW wind turbine were provided by Green Mountain Power (GMP) and for the 100 kW wind turbine by Northern Power Systems (Northern Power).

The critical assumptions for wind projects are the installed capital costs, capacity factors, and fixed O&M expenses which include all annual recurring non-capital expenses such as property taxes and insurance.

Northern Power initially indicated that the cost of a 100 kW wind turbine would be about \$5,850/kW based on two installations outside of Vermont. Northern Power subsequently increased its project cost estimate to reflect higher assumed interconnection costs in Vermont based on an estimate provided by Central Vermont Public Service. Power Advisory increased Northern Power's cost estimate to reflect these higher interconnection costs. We weren't able to confirm validity of Northern Power's claims that interconnection costs would be significantly higher in Vermont than were reflected in the initial project cost estimates.

The capacity factor provided by GMP for the 1.5 MW wind turbine was used for the analysis. Northern Power originally proposed a range of capacity factors from 20 to 25%. Northern Power supplemented this information with a capacity factor estimate based on an analysis that it performed of the zip codes in Vermont that offered the top 20% of wind regimes in the state. Power Advisory doesn't find this analysis very compelling.¹³ The analysis appears to consider the average wind speed in a municipality and doesn't differentiate between microclimates within a municipality which can have a significant impact on wind speed. For example, TrueWind Solutions, LLC (TrueWind) notes that as a general rule of thumb wind speeds increase by 1 meter/second for every 100 meters in elevation.¹⁴ We would expect proponents to develop projects at sites with the most attractive wind regimes recognizing other siting constraints such as the location of distribution lines, availability of suitable sites in light of site access and permitting considerations. Therefore, we used a capacity factor of 23.8% which is Northern Power's initial high end estimate of 25% adjusted for a 95% turbine availability.¹⁵

¹³ As a point of reference the highest mean wind speeds indicated in the map provided by Northern Power ranged from 5.95 to 6.21 meter/second.

¹⁴ Wind Resource Maps of Northern New England, June 2, 2003, p. 8. TrueWind notes that this is most applicable to small, isolated hills and ridge lines in otherwise flat terrain.

¹⁵ Northern Power also cited the capacity factor of GMP's Searsburg Project as evidence of the reasonableness of its estimate of a 20% capacity factor. Power Advisory understands that the Searsburg Project's capacity factor has been adversely affected by various issues associated with the project's location and the need to modify the turbines and maintenance practices to respond to the challenges posed by cold weather climate.

Power Advisory evaluated the required standard offer price with and without a \$250,000 CEDF grant. The CEDF had a \$5/MWh impact on the required standard offer price, with the price at \$119/MWh without the CEDF grant. Given the relatively favorable economics of the project we assumed that no CEDF grant would be provided. The modeling results suggest that the Statutory default price is a reasonable approximation for the 1.5 MW project.

The required price for the 100 kW project is projected to be approximately \$215/MWh. Power Advisory relied heavily on the assumptions provided by Northern Power and wasn't able to independently evaluate the reasonableness of these estimates. Given the limited support for the underlying assumptions, Power Advisory has limited confidence in our estimate and doesn't express an opinion on the reasonableness of the default price if the Board were to choose to establish 100 kW wind as a separate category for its September 15, 2009 determinations.

Table 1: Wind Project Assumptions and Projected Standard Offer Prices

Project	1.5 MW	100 kW
Installed Capital Cost (\$/kW)*	\$3,000	\$6,750
ITC (%)	33.6%	33.6%
Grant (\$/kW) before tax		\$250,000
Fixed O&M (\$/kW-year)	\$72	\$142
Capacity Factor	26.6%	23.8%
Debt/Equity Ratio	60/40	60/40
Debt Term	18	18
Contract Term	20	20
Price (\$/MWh)	\$119	\$215
Default Price per Act 45 (\$/MWh)	\$125	\$125

3.2 Farm Methane

Three sizes of farm methane projects were evaluated: 300, 65 and 35 kW. The largest project size is representative of a 1,000 cow farm. The assumptions were provided by the Vermont Agriculture Department (Agriculture Department) based on existing projects for large farms. These data were then used to estimate the costs for the smaller farm projects of 65 kW and 35 kW. Project specific detail was provided regarding revenues from the sales of byproducts, the value of federal and state grants, interconnection costs, and maintenance and staffing expenses.

The Agriculture Department proposed alternative assumptions for project financing and marginal tax rates for the farmers who would own and operate these projects. Specifically, the Agriculture Department noted that these projects were financed using more conventional real estate loans with the collateral based on farm real estate. The Agriculture Department noted that the typical loan term is 7 years. Given that these assumptions represent a significant departure from what is assumed for other technologies, Power Advisory independently assessed their reasonableness by contacting various individuals who have experience with farm lending. These individuals indicated that the duration of the loan can approach the term of power purchase agreement and that lenders may look more favorably on the loan than a conventional real estate loan since the investment would be generating positive cash flow.¹⁶ Furthermore,

¹⁶ The agricultural lending expert from Yankee Farm Credit noted that consideration would be given to the useful life of the equipment and the risks that this posed.

the interest rates on these loans will be based on those offered for conventional real estate loans to farmers. Given the uncertainty regarding the useful life of the gen set under these applications, Power Advisory believes that a ten-year loan term is reasonable.¹⁷ With the loan based on real estate which has a clear market value and on current credit market conditions we believe that an interest rate of 5.5% is reasonable.

Given that these projects are likely to be owned by farmers, federal and state tax rates that consider their income levels were proposed and used, i.e., owners of large projects (300 kW) were assumed to have a marginal federal tax rate of 20% and state tax rate of 5% and owners of medium and small projects (65 and 35 kW) were assumed to have a marginal federal tax rate of 15% and state tax rate of 5%.

Finally, the Act specifies that the plant owner of farm methane projects shall retain the tradeable renewable energy credits. Therefore, Power Advisory assumed that the owner would be able to sell these to generate revenue and reduced the required standard offer price to account for this anticipated revenue stream.¹⁸

The levelized prices resulting from the Power Advisory modeling for the three project sizes range from \$157 (300 kW project) to \$539/MWh (35 kW project). These modeling results suggest that the default price of \$120/MWh isn't a reasonable approximation of price required to enable the development of Farm Methane projects. Table 2 below summarizes the assumptions and modeling results (i.e., levelized price over the 20-year term of the contract in \$/MWh)

Table 2: Farm Methane Project Assumptions and Projected Standard Offer Prices

Technology	Farm Methane		
Source of Estimates	Vermont Ag Department & Power Advisory		
Project	Large Farm	Medium Farm	Small Farm
Net Capacity (kW)	300	65	35
Installed Capital Cost (\$/kW)*	\$ 7,628	\$ 12,308	\$ 15,714
ITC (%)	0%	0%	0%
Grant (\$/kW) before tax	\$ 1,928	\$ 7,654	\$ 10,696
Fixed O&M (\$/kW-year)	\$ 767	\$ 1,801	\$ 2,936
Offsetting Revenue (\$)**	\$ 95,000	\$ 22,500	\$ 12,750
Capacity Factor	76.5%	76.5%	76.5%
Debt/Equity Ratio**	75/25	75/25	75/25
Debt Term	10	10	10
Contract Term	20	20	20
Price (\$/MWh)	\$ 157	\$ 329	\$ 539
Default Price per Act 45 (\$/MWh)	\$ 120	\$ 120	\$ 120

¹⁷ The debt service coverage ratios also begun to drop below one at ten years for the smaller size projects suggesting that a longer term loan could drain cash from other uses.

¹⁸ If no credit is taken for the projected market value of these tradeable renewable energy credits the standard offer price for a 300 kW project would be \$187/MWh, an increase of \$30/MWh.

3.3 Solar PV

Table 4 below summarizes the assumptions and modeling results (i.e., levelized price over the 25-year term of the contract in \$/MWh) for the various sizes of solar projects evaluated. Four different project sizes were evaluated: 15 kW, 150 kW, 500 kW and 2.2 MW projects.

Divergent assumptions regarding the cost and performance of solar PV systems were provided initially by consultants to REV and the DPS. A third set of assumptions were offered by Longview Infrastructure LLC regarding a larger scale project that they were evaluating in Vermont.

The critical assumptions for solar projects are the installed capital costs, fixed O&M expenses which include all annual recurring non-capital expenses such as property taxes and insurance and the capacity factor. The REV consultant indicated that its capital cost estimates were based on a survey of members. It provided various alternative sources to demonstrate the reasonableness of the estimates. One source that was identified was the Massachusetts Technology Collaborative (MTC) PV project installation database. The database indicated project installation costs and the date installed. This database could be sorted and screened to establish installation costs for recent projects (recognizing that PV projects are experiencing significant cost declines) and to reflect the most cost-efficient project installations. When this database was used in this way it indicated that the REV capital costs estimates were not in fact low.

Power Advisory's PV capital cost estimates were based on the MTC database. Specifically, we sorted PV projects based on their installation dates and costs and then estimated the average installed cost after screening out the highest cost projects. Specifically, we eliminated one-third of projects with the highest cost and for project sizes less than 150 kW only considered projects that were installed since the first quarter of 2009.¹⁹ Given the significant PV price reductions that have been experienced in 2009 (reported to be from 20 to 40%) we assumed another 5% reduction in project costs to reflect the likelihood that additional cost reductions can be realized that are not reflected in the MTC database given lags associated with when project costs are established. The largest project installed in the MTC database was about 400 kW, so we used the costs for the largest class of projects in the database to estimate the installed cost for a 2.2 MW project and assumed an additional 5% savings in the \$/kW cost to reflect economies of scale.²⁰ The capital cost estimates used are presented in Table 3.

Table 3: PV Capital Cost Estimates

Size	≤ 15	15 kW – 150 kW	150 kW – 500 kW	500 kW – 2.2 MW
Installed Cost (\$/watt dc)	\$7.01	\$6.07	\$5.70	\$5.41

Source: MTC, Power Advisory

REV assumed capacity factors of 13%. DPS assumed capacity factors of 15% for the larger than 15 kW projects. Smaller projects (500 kW and smaller) more typically will be roof-mounted. Given that the orientation of the panels can be limited by the orientation of the roof, these systems will likely have slightly lower capacity factors than ground-mounted systems. Therefore, we assumed that the 500 kW and smaller projects would have capacity factors of 13% and larger projects would have capacity factors of 14%.²¹

¹⁹ There were only eleven projects larger than 150 kW, so a decision was made to not screen these projects based on their installation date. (There were only four greater than 150 kW projects installed after the first quarter of 2009.) These projects generally had lower costs so the decision to not screen these projects based on their installation date resulted in a higher cost estimate.

²⁰ Some of these savings may be offset by land lease expenses for the 2.2 MW ground mounted project. However, these are assumed to be accounted for in the O&M cost estimates proposed by REV.

²¹ We have used similar capacity factor estimates for other solar PV cost analyses.

The levelized prices range from \$283/MWh (2.2 MW project) to \$384/MWh (15 kW project). The results suggest that if the Board were to further differentiate the resource by size categories of 15 kW and below and 15 to 150 kW then the Statutory defaults may be below those reasonably approximate costs. The Statutory default prices are reasonably close to the Power Advisory estimates for project sizes of 500 kW and 2.2 MW. Given the costs risks posed by larger solar PV projects (which have the highest prices and have had significant market uptake in other jurisdiction) the Board may wish to exercise additional caution regarding the largest solar PV projects and revise down the Statutory default price to a level that is closer to the Power Advisory estimate.²²

Table 4: PV Project Assumptions and Projected Standard Offer Prices

Project	< 15 kW	15-150 kW	150-500 kW	500-2.2 MW
Net Capacity (kW)	15	150	500	2,200
Installed Capital Cost (\$/kW)*	\$7,010	\$6,070	\$5,700	\$5,415
ITC (%)**	60%	60%	60%	60%
Fixed O&M (\$/kW-year)	\$104	\$91	\$86	\$82
Capacity Factor	13%	13%	13%	14%
Debt/Equity Ratio**	50/50	50/50	50/50	45/55
Debt Term	18	18	18	18
Contract Term	25	25	25	25
Price (\$/MWh)	\$384	\$335	\$316	\$283
Default Price per Act 45 (\$/MWh)	\$ 300	\$ 300	\$ 300	\$ 300

**Vermont ITC utilized over 5-years.

3.4 Hydro

Table 5 below summarizes the assumptions and modeling results (i.e., levelized price over the 20-year term of the contract in \$/MWh) for a composite hydro project which is based on the project cost and operating performance assumptions for three different small hydro projects that are under development in Vermont. The assumptions were provided by Great Bay Hydro Corporation for a project that it has under development and two projects under development by Community Hydro.

Credit was taken for a 30% Federal ITC on 90% of the project capital costs. Given the assumed 30-year life of the project, a credit for the project's residual value was taken at the end of the contract term based on the undepreciated (book) value of the project in year 21. A maintenance reserve charge of \$20,000 per year which escalated at inflation was included.

The required levelized price for the composite project was \$135/MWh which isn't out of line with the Statutory default price of \$125/MWh. These modeling results suggest that the default price is a reasonable approximation of the price required to enable the development of hydro projects.

²² Power Advisory notes that GMP indicated that it was able to build solar PV projects for less than \$250/MWh. (Supplemental Comments Offered Regarding the Cost Analysis Subgroup Report)

Table 5: Hydro Project Assumptions and Projected Standard Offer Prices

Technology	Hydro
Source of Estimates	Average Hydro
Project	Composite Project
Net Capacity (kW)	1,278
Installed Capital Cost (\$/kW)*	\$ 4,173
ITC (%)	33.6%
Grant (\$/kW) before tax	\$ -
Fixed O&M (\$/kW-year)	\$ 162
Capacity Factor	44.9%
Debt Term	18
Asset Life	30
Price (\$/MWh)	\$ 135
Default Price per Act 45 (\$/MWh)	\$125